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Staff

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DIRECT TESTIMONY

of

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Rate Analyst**

Rates Department
Financial Analysis Division
Illinois Commerce Commission

Proposed General Increase in Gas Rates

Mid American Energy Company

Docket No. 01-0696

March 1, 2002

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Witness Identification

1 Q. Please state your name and business address.

2 A. Mike Luth, Illinois Commerce Commission ("Commission"), 527 East Capitol
3 Avenue, Springfield, Illinois 62701.

4 Q. What is your present position with the Commission?

5 A. I am currently a Rate Analyst in the Rates Department of the Financial Analysis
6 Division. In that position, I review and analyze tariff filings by electric and gas
7 utilities with regard to cost of service and rate design. I make recommendations
8 to the Commission on such filings and participate in docketed proceedings as
9 assigned. In this docket, I evaluated the cost of service and rate design aspects
10 of the natural gas tariffs proposed by MidAmerican Energy Company ("MEC" or
11 the "Company").

12 Q. Please state your professional qualifications and work experience.

13 A. I received a B.S. in Accounting from Illinois State University. I have earned the
14 C.P.A and C.M.A professional designations. Since graduating, I have worked as
15 an Assistant Property Manager with a real estate company and as a Field Auditor
16 with the Wisconsin Department of Revenue. In October of 1990, I joined the
17 Accounting Department of the Commission ("Commission"). In June 1998, I
18 transferred from the Accounting Department of the Commission to the Rates
19 Department.

20 Q. Have you testified in any previous Commission dockets?

21 A. Yes. I have testified on numerous occasions before the Commission.

Introduction to Testimony

22 Q. What is the subject matter of your testimony?

23 A. My testimony presents the results of my analysis of the cost of service study
24 ("COSS") prepared by MEC witness Charles B. Rea and the rate design
25 proposals of MEC witness Gregory C. Schaefer.

26 Q. Are you sponsoring any schedules as part of your testimony?

27 A. Yes, I am sponsoring the following schedules:

Schedule 1	Rate Design
Schedule 2	Customer Class Allocation Factors
Schedule 3	Peak Demand Estimation
Schedule 4	Calculation of Load Factor
Schedule 5	Functional Allocation Factors

Summary of Findings

28 Q. Please summarize your findings.

29 A. My proposed rates begin with the COSS developed by Mr. Rea, adjusted for
30 some differences in class and functional allocation factors. The differences in the
31 class and functional allocation factors resulted in differences in the rates
32 proposed by the Company and the rates that I've determined. The Company's
33 proposals are also affected by the difference in Staff's recommended revenue
34 requirement compared to the Company's proposed revenue requirement.

35 The most significant difference in rates is probably in the structure of Rates 70
36 and 85, which are available to commercial and industrial gas customers. Rate 70
37 and Rate 85 customers have the option of providing their own gas supply,
38 thereby being referred to as transportation customers, or allowing the Company
39 to supply them with gas, referred to as sales customers. The Company's
40 proposed rates would charge the same distribution energy rate for Rate 70
41 customers, regardless of whether the customer is a sales customer or a
42 transportation customer. Similarly, MEC would charge the same distribution
43 energy charge for Rate 85 customers, again without distinction between sales
44 and transportation customers. My proposed Rate 70 and Rate 85 rate structures
45 differentiate between sales and transportation customers, charging less for the
46 distribution energy charges for transportation customers compared to sales
47 customers. Under my proposal, transportation customers are not charged for
48 energy-related costs, but sales customers are, resulting in different rates for
49 transportation customers and sales customers.

Class Allocation

- 50 Q. Why does your COSS have some class allocation factors that are different than in
51 the COSS developed by MEC witness Rea?
- 52 A. Some of the class allocation factors in the COSS presented by Mr. Rea have
53 significantly changed compared to similar allocation factors employed in the
54 previous MEC gas rate case, Docket No. 99-0534, but the changes have not
55 been adequately explained by the Company. Given that Docket No. 99-0534

56 occurred just over two years ago, the differences in allocation factors should be
57 adequately explained or should change only to a small degree.

Weighted Services, Meters and Regulators

58 Q. Did you ask the Company about the differences in class allocation factors?

59 A. Yes, I did. In Staff data requests ML-13 through ML-15, I asked about the
60 significant differences in the relative rate class weightings for services, meters
61 and regulators. MEC replied that the calculations for the factors used by the
62 Company in this docket are shown in the Company's testimony and in the reply to
63 Staff data request ML-4. The Company's replies to Staff data requests ML-13
64 through ML-14 also state that the relative class weightings from Docket No. 99-
65 0534 were provided by the Company's COSS consultant from that docket and are
66 not available. I find the Company's inability to provide these materials
67 problematic.

68 The Company's proposed weighting factors for Services, Meters and Regulators
69 for Rate 60 were 1 in Docket No. 99-0534 and remain 1 in this docket. However,
70 for the other customer classes, MEC has proposed fairly substantial changes in
71 the weighting factors, as shown in the following table:

	Rate 70	Rate 85	Rate 87
Services			
Docket No. 99-0534	5	15	7.5
MEC proposed, this docket	1	2	1
Percentage change	-80%	-87%	-87%
Meters			
Docket No. 99-0534	5	125	35
MEC proposed, this docket	7	60	8
Percentage change	+40%	-52%	-77%
Regulators			
Docket No. 99-0534	5	125	35
MEC proposed, this docket	7	60	8
Percentage change	+40%	-52%	-77%

72 Rate 60 is excluded from the table because the weighting factors for these
73 allocation factors remain at 1 in this docket, which is the same weighting as in
74 Docket No. 99-0534.

75 Q. How did the MEC replies to Staff data requests ML-13 through ML-15 affect your
76 conclusions concerning relative class weightings for services, meters and
77 regulators?

78 A. Given that Docket No. 99-0534 occurred just over two years ago, that the relative
79 class weightings for services, meters and regulators were found to be fair and
80 reasonable in that docket; and that the number of gas customers in the test year
81 in this docket has grown less than 1 percent, I think it is important that the
82 proposed changes in these weightings be properly explained and justified. Based

upon the Company's reply to Staff data requests ML-13 through ML-15, a comparison of the relative class weightings proposed by MEC in this docket to the calculation of the relative class weightings in Docket No. 99-0534 cannot be made. Without a comparison to the allocation factors employed in Docket No. 99-0534, an explanation of the changes is not complete. As a result, I used the relative class weightings from Docket No. 99-0534 for services, meters and regulators. The Services, Meters and Regulators weighting factors are shown on Schedule 2, pages 1 and 2, items VI, VII, VIII and IX.

Q. How does a change in customer class weighting factors affect a COSS?

A. If the number of customers remains constant, an increased weighting factor increases the percentage of costs allocated to a given rate class, while a decrease in a weighting factor decreases the costs to a given rate class. For example, if two rate classes both have 20 customers, but a services weighting factor of 4 applies to one rate class and a services weighting factor of 1 applies to the other rate class, total weighted services is 100 ($20 \times 4 = 80$, $20 \times 1 = 20$, $80 + 20 = 100$). The rate class with a weighting factor of 4 will be allocated 80 percent (80 out of the total of 100) of the services-related costs, while the other rate class will be allocated 20 percent of the services-related costs (20 out of the total of 100), despite having the same number of customers. In this docket, the considerable decreases in weightings for Rate 85 and 87 proposed by MEC have the effect of increasing the allocation of costs to Rate 60, and to a lesser degree, Rate 70.

105 Q. What class allocation factors in your COSS differ from those used by MEC
106 witness Rea in his COSS?

107 A. In addition to the differences in the Services, Meters and Regulators customer
108 class allocation factors, there is a difference in the Peak Demand allocation
109 factors (items II and III on Schedule 2) and the Weighted Customers – Customer
110 Service allocation factor (item X on Schedule 2).

Peak Demand Allocation Factor

111 Q. Why is there a difference in the Peak Demand allocation factors?

112 A. There are two Peak Demand allocation factors, one for the sales customers
113 within each rate class, and one for the rate class as a whole. Although MEC
114 witness Rea did not explain the calculation of the Company's proposed Peak
115 Demand allocation factors, the Company's proposed Peak Demand allocation
116 factors are based upon a projection applied to the system-design peak. The
117 projection is calculated by determining the slope of the monthly sales to a given
118 customer class compared to the monthly heating degree days, and determining
119 an intercept value of monthly sales at zero heating degree days. The slope is
120 multiplied by 90 which is the number of heating degree days assumed in the
121 system-design peak. The product is then added to the intercept of monthly sales
122 at zero heating degree days.

Mr. Rea's projection contradicts the system's actual peak demand and trends in consumption. One problem is that the MEC Illinois gas all-time peak is 1,143,026 therms in a day (Page 14 of attachment in reply to Staff data request ML-9), not the 1,193,551 therms calculated by Mr. Rea's projection (MEC Exhibit__(CBR-4)). Another problem is that Mr. Rea's projection results in Rate 60 having a peak demand of 21.6% more than the Rate 60 peak demand in Docket No. 99-0534, while the number of Rate 60 customers has grown by only 0.7%. Although the number of Rate 60 customers has grown, albeit by only 0.7%, weather-normalized Rate 60 sales are 4.6% lower, which suggests that peak day sales may also be lower. Total jurisdictional Illinois Gas peak demand is projected by Mr. Rea to be 14.7% higher than in Docket No. 99-0534, but the number of customers in all rate classes has grown by only 0.725%. Finally, the intercept or zero heating degree day Rate 60 load projected by Mr. Rea's COSS is 1,079,327 therms in an average month of zero heating degrees days. However, the months of July and August had zero heating degree days with Rate 60 sales of 1,277,596 therms and 1,310,290 therms respectively. The actual July and August zero heating degree day months averaged more than 19% greater therms of consumption by Rate 60 than the estimate for a zero heating degree month in Mr. Rea's COSS. With an understated intercept, the slope appears to be overstated for Rate 60, thereby overstating the effect of heating degree days when projecting peak sales.

Q. How did you determine Peak Demand allocation factors?

145 A. My Peak Demand allocation factors are based upon the peak demands approved
146 by the Commission in Docket No. 99-0534, increased or decreased by the
147 percentage of change in number of customers for each rate class. This is a
148 reasonable approach, given that the billed Maximum Daily Requirement ("MDR")
149 for Rate 85 stood at 88,500 therms in December 2000 (WP GCS-3b), and given
150 the apparent trend of lower therms per Rate 60 customer discussed previously.

Weighted Customers – Customer Service

151 Q. How is the Weighted Customers – Customer Service allocation factor (Schedule
152 2, page 2, item X) different from the Weighted Customers – Services (Schedule
153 2, page 2, item VI) allocation factor?

154 A. These two factors allocate different costs. The Customer Service allocation
155 factor allocates customer-related costs such as customer accounts expenses.
156 The Services allocation factor allocates costs related to providing gas service to
157 the customer's location, such as the pipe and related expenses from the
158 distribution line to the customer's meter.

159 Q. Why is there a difference in the Weighted Customers – Customer Service
160 allocation factor?

161 A. There are two reasons for the difference in the Weighted Customers – Customer
162 Service allocation factor. The first reason is that Mr. Rea rounded the class
163 weights to whole numbers, rather than two decimal points. Given the magnitude
164 of allocating \$3.8 million in customer service costs to 65,319 customers, it is

165 appropriate to weight the classes to a greater level of detail resulting from a
166 rounding to two decimal points. For example, a rounding of a customer weight
167 from 2.49 down to 2 would reduce the weighting of the customer class by nearly
168 20 percent. Moreover, with the use of personal computers, it is not difficult to
169 weight the customer classes to two decimal points.

170 The other reason for the difference in the Weighted Customers – Customer
171 Service allocation factor is that the Company allocated marketing costs to the
172 customer classes according to margins. In contrast, I allocated marketing costs
173 according to throughput because the classes with the larger volumes subject to
174 transportation represent the classes with the largest potential market for MEC to
175 be the supplier of gas. This difference resulted in heavier class weightings for
176 Rates 85 and 87, with some reduction in the class weight for Rate 70. The
177 difference in class weightings for marketing should not be considered drastic,
178 however, because Rate 70 is allocated 70% of marketing costs under my
179 approach, compared to 85% under the MEC approach. Weighting marketing
180 costs on the basis of throughput is also appropriate because, as MEC witness
181 Schaefer has stated (Direct Testimony of Gregory C. Schaefer, page 8, lines 198
182 through 200), Rate 70 has a wide range of customers who do not consume large
183 volumes of natural gas and are thus less likely to be attractive to potential supply
184 competitors. More than 90% of Rate 70 customers are billed for total monthly
185 gas volumes within the first block of Rate 70, which is 1,000 therms or less in a
186 month (MEC WP GCS-3c, pages 4, 6, 10 and 12). By comparison, Rate 85

187 customers consumed an average of 181,652 therms per month and Rate 87
188 customers consumed an average of 17,857 therms per month.

Functional Allocation

189 Q. What is the difference between a functional allocation factor and customer class
190 allocation factor?

191 A. A functional allocation factor allocates costs recorded in the Company's accounts
192 by the type of costs in those accounts. Functions are shown in the items listed
193 under the sub-headings on page 5 of my Schedule 1. After the costs for each
194 account have been allocated according to function, the costs in each function are
195 totaled. The total costs for each function are then allocated to the customer
196 classes using customer class allocation factors shown in the right-hand column
197 on page 5 of my Schedule 1. The customer class allocation factors are detailed
198 on my Schedule 2.

199 Q. Are there any differences in the functional allocation of any accounts between
200 the Company's COSS and your COSS?

201 A. Yes, there are a few differences. I allocated account 923 – Outside Services
202 according to payroll, instead of supervised operating and maintenance expense
203 ("O & M"). I allocated account 925 – Injuries and Damages by weighting field
204 distribution payroll by a factor of 90%, and office payroll (accounts 901-935) by
205 the remaining 10%. Finally, I allocated account 931 – Rents by the combination

206 of customer service, accounting, sales and administrative and general ("A & G")
207 expenses, rather than supervised O & M.

208 Q. Why have you allocated account 923 – Outside Services by function according to
209 payroll, instead of supervised operating and maintenance expense?

210 A. This is an A & G account that records the costs for professional consultants and
211 others that are not directly chargeable to other functions. The account can be
212 considered a payroll account because it involves the payment for services
213 rendered by people who might be employed by the Company if the Company
214 had sufficient recurring need for the people with the skills needed on a temporary
215 or intermittent basis. Since the costs in the account cannot be directly charged
216 to other functions, and represent payments for the services of people outside the
217 Company's payroll, it is reasonable to allocate the costs by function according to
218 the payroll of each function.

219 Q. Why have you weighted payroll heavily toward field distribution in allocating
220 account 925 – Injuries and Damages by function?

221 A. This account records costs associated with claims against the Company for
222 Injuries and Damages to the Company's employees, people outside of the
223 Company, or to the property of others. It also records the cost of insurance for
224 claims of employees or others resulting from the Company's activities. It is
225 reasonable to expect that activities related to operating and maintaining gas
226 distribution equipment in the field are considerably more risky than activities
227 related to MEC employees involved in office activities such as customer
228 accounts and A & G, so a heavier weighting should be given to distribution
229 payroll compared to office payroll.

230 Q. Why have you allocated account 931 – Rents by function according to customer
231 service, accounts, sales, and A & G expenses rather than supervised O & M?

232 A. Costs recorded in this account represent costs for the property of others used,
233 occupied or operated in connection with customer accounts, customer service
234 and informational, sales and A & G functions of the utility. The Company's
235 supervised O & M functional allocation factor includes distribution-related costs.
236 Rents for distribution-related property should be recorded in Rent accounts
237 directly chargeable to distribution, such as accounts 860 and 881. My allocation
238 factor reflects the division of customer and A & G costs according to function,
239 and applies the costs of equipment rented to assist in customer and A & G
240 activities according to how the MEC functions are served by customer and A & G
241 activities.

Rate Design

242 Q. What is the effect of your COSS on rates?

243 A. A table of my proposed rates for MEC natural gas service is shown on page 1 of
244 Schedule 1. Each rate class has a proposed monthly customer service charge
245 and a distribution energy charge per therm of consumption. Rates 70, 85 and 87
246 have a proposed monthly transportation administrative charge ("TAC"),
247 applicable only to transportation customers. Rate 85 has a distribution demand
248 charge per therm of MDR.

249 Q. In general, what types of costs are recovered from the different charges?

250 A. A customer charge recovers customer-related costs that theoretically do not vary
251 with consumption or demand. A distribution energy charge recovers costs
252 associated with average use of the system, and for sales customers, costs of
253 securing gas supply. If a rate class is not demand-metered, which is the case
254 with Rates 60, 70 and 87, the distribution energy charge also recovers peak
255 demand-related costs theoretically caused by the use of the system on the
256 maximum day of gas delivery. A distribution demand charge recovers peak
257 demand-related costs if the rate class is metered for demand, which for MEC, is
258 Rate 85 only. A TAC recovers customer costs caused by transportation
259 customers and is therefore not applicable to sales customers.

Rate 60

260 Q. What are your proposals for Rate 60?

261 A. My proposals for Rate 60 are based upon my COSS, Staff's recommended
262 revenue requirement and current rates. The structure of my proposed Rate 60 is
263 similar to MEC's proposal for Rate 60 in that I am proposing a monthly customer
264 charge and a distribution energy charge per therm consumed. Although my
265 proposed structure of Rate 60 is the same as MEC's, the charges are different.
266 The difference in amounts is the result of the difference in my COSS results and
267 the difference in the Staff recommended revenue requirement.

268 My COSS indicates that Rate 60 would have a lower distribution energy charge
269 than what is presently charged, and a higher customer charge than what is
270 presently charged, although lower than what MEC is proposing. My proposed
271 rates adjust the situation of an increased customer charge combined with a lower
272 distribution energy charge by maintaining the distribution energy charge at the
273 current rate per therm consumed, while increasing the monthly customer charge
274 by less than the amount indicated by the COSS. This approach recovers costs
275 from the Rate 60 customer class at approximately the overall class revenue
276 requirement, and attempts to maintain a continuity of charges in Rate 60.

Rate 70

277 Q. What are your proposals for Rate 70?

278 A. My proposals for Rate 70 are based upon my COSS, Staff's recommended
279 revenue requirement and current rates. The structure of my proposed Rate 70 is
280 similar to MEC's proposal for Rate 70 in that I am proposing a monthly customer

charge, a monthly TAC if applicable, and a distribution energy charge per therm consumed. The structure of my proposed Rate 70 is different, however, in that the amounts for the proposed charges are different with a distinction between sales and transportation customers. I am also proposing to maintain the current declining block structure for the distribution energy charge per therm, compared to MEC's proposal, which has the same charge for the first two usage blocks in Rate 70 followed by a decline in the highest consumption block.

Q. How does your proposed Rate 70 customer charge differ from the customer charge proposed by MEC?

A. MEC is proposing that the Rate 70 customer charge be the same as the customer charge for Rate 60. I am proposing that the customer charge be set at \$25.00 per month, which is substantially less than the amount indicated by the COSS, but considerably closer to the COSS than the \$12.00 proposed by MEC. The MEC proposal would result in a small decrease in the Rate 70 monthly customer charge, with the customer charge set considerably lower than indicated by the COSS. MEC made this proposal to reflect the wide range of small natural gas consumers under Rate 70. I agree that smaller Rate 70 customers should be considered in determining a monthly customer charge, but at the same time, an understated customer charge creates a problem of under-recovered customer costs. With an understated customer charge, customer-related costs need to be recovered through the Rate 70 distribution energy charge. MEC proposes to recover the remaining customer-related costs through the first two consumption

303 blocks of Rate 70, which are 0 to 1,000 therms per month and 1,001 to 10,000
304 therms per month. I agree with this proposal also. However, constraining the
305 customer charge to less than one-third of the rate indicated by the COSS results
306 in the first two blocks of the distribution energy charge being disproportionately
307 higher than the charges are now.

308 My COSS indicates that the Rate 70 customer charge should be approximately
309 \$45 per month or more. In order to consider small Rate 70 customers, while
310 moving the customer charge closer to the Rate 70 COSS result, I propose that
311 the customer charge be \$25.00. While this is higher than my proposed Rate 60
312 residential customer charge, it is still not excessive for a commercial customer.
313 This increase in the customer charge also reduces the impact of unrecovered
314 customer-related costs on the first two blocks of the distribution energy charge,
315 so that the increase in the distribution energy charge is not as considerable as it
316 would have been had the customer charge been set at the Rate 60 level.
317 Furthermore, the increase in the customer charge will be offset for the small Rate
318 70 customer through a lower distribution energy rate per therm consumed and
319 billed in the first two blocks of Rate 70.

320 Q. How does your TAC differ from the amount proposed by MEC?

321 A. My proposed TAC is higher than the \$75 proposed by MEC as a result of the
322 differences between my COSS and the MEC COSS. The increase is offset to
323 some degree by the elimination of the Transportation Metering Charge.

324 Q. How do your proposed Distribution Energy charges differ from those proposed by
325 MEC?

326 A. My proposed rates are higher for sales customers compared to transportation
327 customers, and maintain a declining block structure through the first two Rate 70
328 consumption blocks for both sales and transportation customers. MEC proposes
329 that the distribution energy charge be the same for transportation customers and
330 sales customers, and that the same rate per therm be charged through the first
331 two consumption blocks.

332 The differences in my proposed rates for sales customers compared to
333 transportation customers result from eliminating energy-related costs from
334 transportation rates. Since transportation customers arrange their own supplies
335 of gas, it is not appropriate to charge them for gas supply expenses incurred by
336 MEC. Page 4 of my Schedule 1 develops an energy costs factor per therm for
337 sales customers, which is included in the block charges for sales customers but
338 not transportation customers. Both the sales and the transportation distribution
339 energy rates recover demand-related costs.

340 I am maintaining a declining structure for the first two blocks of the Rate 70
341 distribution energy charges so that more of the customer-related costs are
342 recovered per therm in the first consumption block compared to the second
343 consumption block. Since customer-related costs do not theoretically vary with

344 consumption, it is appropriate the customer-related costs not recovered by the
345 understated Rate 70 customer charge be more quickly recovered in the first
346 consumption block under my proposed declining block structure.

Rate 85

347 Q. What are your proposals for Rate 85?

348 A. Like MEC, I am proposing a monthly customer charge, a monthly TAC if
349 applicable, a distribution demand charge and a distribution energy charge. Unlike
350 MEC, my proposed distribution demand and energy charges are lower for
351 transportation customers compared to sales customers.

352 Q. How are your monthly customer and TAC's different from the MEC proposals for
353 these charges?

354 A. My proposed monthly customer and transportation administrative charges are
355 higher than the similar Rate 85 amounts proposed by MEC. The differences are
356 primarily the result of differences in my COSS compared to the Company's
357 COSS.

358 Q. How are your monthly distribution demand and distribution energy charges
359 different from the comparable MEC proposals?

360 A. My proposed distribution demand rates are lower than the MEC proposed rates.
361 The sales distribution demand rate is somewhat higher than the transportation
362 distribution demand rate because an adjustment is made to the transportation

rate so that costs over-recovered through the TAC are offset through the adjustment to the transportation distribution demand charge. Peak demand-related costs are recovered through my proposed distribution demand charge divided by MDR therms for Rate 85.

My proposed distribution energy rates are higher than the MEC proposed rates. The ratio of average demand-related costs to peak demand related costs is higher under my COSS than the ratio used in MEC witness Rea's COSS. Mr. Rea calculates the ratio based upon the system design peak of 1,513,380 therms (MEC Exhibit__(CBR-3). My review indicates that the system's all-time peak of 1,143,026 therms was set in February 1996 (page 14 of attachment to reply to Staff data request ML-9), so the system design peak appears to be irrelevant at this time in determining how peak demand-related costs are affected by the current use of the system. The system design peak is 32% higher than the all-time peak set six years ago. I have based the ratio of average demand-related costs to peak demand-related costs upon the all-time system peak, rather than the system design peak, so average demand-related costs in my COSS are higher than in the MEC COSS. Although it is not clear whether Rate 85 average demand-related costs are recovered through the distribution energy charge proposed by MEC witness Schaefer, a difference in the ratio of average demand-related costs to peak demand-related costs would be a reason why my proposed distribution demand charge for Rate 85 is lower than the proposal by MEC, and why my proposed distribution energy charge is higher than the proposal by MEC.

385 The distribution energy charge that I am proposing for Rate 85 transportation
386 customers is less than the comparable charge for Rate 85 sales customers. As
387 with Rate 70, I am proposing to recover energy-related costs through the charge
388 to sales customers only because transportation customers arrange for their own
389 gas supply. Transportation customers should therefore not be charged for gas
390 supply costs incurred by MEC, which I accomplish through a lower proposed
391 distribution energy charge for Rate 85 transportation customers compared to the
392 Rate 85 sales customers.

Rate 87

393 Q. What are your proposals for Rate 87?

394 A. My proposed structure of Rate 87 is the same as that for the Company, in that I
395 am proposing a monthly customer charge, a monthly TAC and a distribution
396 energy charge per therm consumed. As with Rates 60, 70, and 85, the amounts
397 that I am proposing for each charge are different from the amounts proposed by
398 MEC. The differences are primarily caused by the difference in the results of my
399 COSS compared to the MEC COSS.

400 Q. Does this conclude your direct testimony?

401 A. Yes, it does.

MidAmerican Energy Company
 Rate Design - Summary of Proposed Rates

	<u>Customer Charge</u> <u>per month</u>	<u>Transportation</u> <u>Administrative</u> <u>Charge per month</u>	<u>Distribution Energy</u> <u>Charge per therm</u> <u>-- Sales</u>	<u>Distribution Energy</u> <u>Charge per therm</u> <u>-- Transportation</u>	<u>Distribution Demand</u> <u>Charge per</u> <u>therm MDR</u> <u>-- Sales</u>	<u>Distribution Demand</u> <u>Charge per</u> <u>therm MDR</u> <u>-- Transportation</u>
Rate 60	\$ 10.30		\$ 0.08051	----	----	----
Rate 70	\$ 25.00	\$ 114.00				
0 - 1,000			\$ 0.11542	\$ 0.10346	----	----
1,001 - 10,000			\$ 0.10281	\$ 0.09085	----	----
10,000 +			\$ 0.06495	\$ 0.05299	----	----
Rate 85	\$ 1,738.00	\$ 114.00	\$ 0.03074	\$ 0.02485	\$ 0.20287	0.20259
Rate 87	\$ 318.00	\$ 114.00	\$ 0.04265	\$ 0.03631	----	----

Distribution Energy Charge for Rate 87 Transportation is the Sales Distribution Energy Charge
 discounted by Energy Costs per therm. \$1,746 divided by 275,696 therms billing units discount.

Mid-American Energy Company Rate Design					
	<u>Net COS</u>	<u>Rate 60</u>	<u>Rate 70</u>	<u>Rate 85</u>	<u>Rate 87</u>
Customer Costs:	\$ 11,759,027	\$ 8,642,307	\$ 2,927,043	\$ 182,828	\$ 6,848
Multiplied by: Staff Revenue Adjustment Factor (see page 6)	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>
	\$ 11,472,407	\$ 8,431,655	\$ 2,855,698	\$ 178,372	\$ 6,681
Less: Over-recovered Demand and Energy Costs (Rate 60 only)	<u>\$ (1,014,790)</u>	<u>\$ (1,014,790)</u>			
Less: Over-recovered Rate 60 Customer Costs				\$ (20,178)	
Net Customer Costs	\$ 10,457,616	\$ 7,416,865	\$ 2,855,698	\$ 158,194	\$ 6,681
Divided by: Total Monthly bills		<u>722,043</u>	<u>61,663</u>	<u>91</u>	<u>21</u>
Monthly Customer Charge		\$ 10.30	\$ 25.00	\$ 1,738.00	\$ 318.00
Multiplied by: Total Monthly bills		<u>722,043</u>	<u>61,663</u>	<u>91</u>	<u>21</u>
Revenue Recovery	\$ 9,143,454	\$ 7,437,043	\$ 1,541,575	\$ 158,158	\$ 6,678
Over/(under) recovery	<u>\$ (1,314,162)</u>	<u>\$ 20,178</u>	<u>\$ (1,314,123)</u>	<u>\$ (20,214)</u>	<u>\$ (3)</u>
Transportation Administration Costs:	\$ 107,202	\$ -	\$ 97,456	\$ 9,746	\$ -
Multiplied by: Staff Revenue Adjustment Factor (see page 6)	<u>0.97563</u>	<u>-</u>	<u>0.97563</u>	<u>0.97563</u>	<u>-</u>
	\$ 104,589	\$ -	\$ 95,081	\$ 9,508	\$ -
Divided by: Total Monthly bills			<u>834</u>	<u>86</u>	
Monthly Transportation Administration Charge			\$ 114.00	\$ 114.00	
Multiplied by: Total Monthly bills			<u>834</u>	<u>86</u>	
Revenue Recovery	\$ 104,880		\$ 95,076	\$ 9,804	
Over/(under) recovery	<u>\$ 291</u>	<u>\$ -</u>	<u>\$ (5)</u>	<u>\$ 296</u>	<u>\$ -</u>
Demand Costs:	\$ 6,091,474	\$ 3,294,032	\$ 2,140,348	\$ 646,835	\$ 10,258
Multiplied by: Staff Revenue Adjustment Factor (see page 6)	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>
	\$ 5,942,997	\$ 3,213,742	\$ 2,088,178	\$ 631,069	\$ 10,008
Distribution Demand Charge per MDR therm (Rate 85 only)				see page 4	
Revenue Recovery	\$ 220,020			\$ 220,020	
Over/(under) recovery	<u>\$ (5,722,977)</u>	<u>\$ (3,213,742)</u>	<u>\$ (2,088,178)</u>	<u>\$ (411,049)</u>	<u>\$ (10,008)</u>

Mid-American Energy Company Rate Design					
	<u>Net COS</u>	<u>Rate 60</u>	<u>Rate 70</u>	<u>Rate 85</u>	<u>Rate 87</u>
Energy Costs:	\$ 998,284	\$ 669,736	\$ 322,410	\$ 4,348	\$ 1,790
Multiplied by: Staff Revenue Adjustment Factor (see page 6)	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>
	\$ 973,951	\$ 653,412	\$ 314,551	\$ 4,242	\$ 1,746
Plus or (minus) under-recovered/(over)-recovered Customer Costs	1,314,162		1,314,123	20,214	3
Plus or (minus) under-recovered/(over)-recovered Transportation Administration Costs	(291)	-	5	(296)	-
Plus or (minus) under-recovered/(over)-recovered Demand Costs	<u>5,722,977</u>	<u>3,213,742</u>	<u>2,088,178</u>	<u>411,049</u>	<u>10,008</u>
	\$ 8,010,800	\$ 3,867,154	\$ 3,716,857	\$ 435,209	\$ 11,758
Divided by: Total Billing units (therms)		<u>60,637,738</u>			<u>275,696</u>
Distribution Energy Charge per therm	\$ 0.08051	see page 3	see page 4		0.04265
Multiplied by: Total Billing units		<u>\$ 60,637,738</u>			<u>\$ 275,696</u>
Revenue Recovery	<u>\$ 9,025,390</u>	<u>\$ 4,881,944</u>	<u>\$ 3,716,664</u>	<u>\$ 415,024</u>	<u>\$ 11,758</u>
Over/(under)-recovery	<u>\$ 1,014,590</u>	<u>\$ 1,014,790</u>	<u>\$ (193)</u>	<u>\$ (20,185)</u>	<u>\$ 0</u>
Total Revenue Recovery	\$ 18,493,744	\$ 12,318,987	\$ 5,353,315	\$ 803,006	\$ 18,436
Total Unadjusted Costs (see page 6)	18,955,986	12,606,075	5,487,257	843,757	18,897
Multiplied by: Staff Revenue Conversion Factor (see page 6)	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>	<u>0.97563</u>
Net Revenues from Base Rates	<u>18,493,944</u>	<u>12,298,809</u>	<u>5,353,508</u>	<u>823,191</u>	<u>18,436</u>
Over/(under)-recovery	<u>\$ (200)</u>	<u>\$ 20,178</u>	<u>\$ (193)</u>	<u>\$ (20,185)</u>	<u>\$ 0</u>

MidAmerican Energy Company
Rate 70 Distribution Energy Charges

	<u>Total</u>	<u>Sales</u>	<u>Transportation</u>	
Energy Costs x Staff Revenue Conversion Factor	\$ 314,551	\$ 314,551		
Demand Costs:				
Average x Staff Revenue Conversion Factor	979,128	658,854	\$ 320,274	Throughput
Peaking x Staff Rev. Conversion Factor	1,109,050	859,731	249,320	Peak
Plus or (minus) under/(over)- recovered customer costs	<u>1,314,123</u>	1,296,463	17,660	Customers
Plus or (minus) under/(over)- recovered transportation admin. Costs			<u>5</u>	
	\$ 3,716,853	\$ 3,129,599	\$ 587,259	
Divided by: Throughput	<u>39,404,125</u>	<u>26,290,065</u>	<u>13,114,060</u>	GCS-1, Schedule 2, page 1
Average per therm	<u>0.09433</u>	<u>0.11904</u>	<u>0.04478</u>	
Average Energy Costs per therm	<u>0.00798</u>	<u>0.01196</u>		
Average Demand Costs per therm	<u>0.05299</u>	<u>\$ 0.05776</u>	<u>\$ 0.04343</u>	
Average Unrecovered Customer Costs per therm	<u>\$ 0.04454</u>	<u>\$ 0.05415</u>	<u>\$ 0.00322</u>	First 2 blocks, GCS-3, page 1
<u>Block Charges per therm:</u>		<u>Sales</u>	<u>Transportation</u>	
0-1,000				
Customer Costs per therm + Block Increase		\$ 0.05047	\$ 0.05047	
Plus: Demand Costs per therm		0.05299	<u>0.05299</u>	
Plus: Energy Costs per therm		<u>0.01196</u>		
		<u>0.11542</u>	<u>0.10346</u>	
Multiplied by: Billing units (therms)		<u>14,859,979</u>	<u>774,706</u>	WP GCS-3a
Revenue Recovery		<u>\$ 1,715,139</u>	<u>\$ 80,151</u>	
1,001-10,000				
Customer Costs per therm x .85		\$ 0.03786	\$ 0.03786	
Plus: Demand Costs per therm		0.05299	<u>0.05299</u>	
Plus: Energy Costs per therm		<u>0.01196</u>		
Distribution Energy Rate per therm		<u>0.10281</u>	<u>0.09085</u>	
Multiplied by: Billing units (therms)		<u>9,163,856</u>	<u>4,706,391</u>	WP GCS-3a
Revenue Recovery		<u>\$ 942,136</u>	<u>\$ 427,576</u>	
10,001+				
Demand Costs per therm		0.05299	<u>0.05299</u>	
Energy Costs per therm		<u>0.01196</u>		
Distribution Energy Rate per therm		<u>0.06495</u>	<u>0.05299</u>	
Multiplied by: Billing units (therms)		<u>2,266,230</u>	<u>7,632,962</u>	WP GCS-3a
Revenue Recovery		<u>\$ 147,192</u>	<u>\$ 404,471</u>	
Total Revenue Recovery		<u>\$ 2,804,467</u>	<u>\$ 912,197</u>	<u>\$ 3,716,664</u>

MidAmerican Energy Company
Rate 85 Distribution Demand and Energy Charges

	<u>Total</u>	<u>Sales</u>	<u>Transportation</u>
Energy Costs x Staff Revenue Conversion Factor	\$ 4,242	\$ 4,242	
Divided by: Billing units (therms)		<u>720,595</u>	
Energy Costs per billing unit		<u>\$ 0.00589</u>	
Demand Costs:			
Average x Staff Revenue Conversion Factor	410,753	17,906	392,847 Throughput
Peaking x Staff Rev. Conversion Factor	220,316	<u>11,319</u>	208,997 Peak
Plus or (minus) under/(over)- recovered transportation administration costs	<u>(296)</u>		<u>(296)</u>
	<u>\$ 635,015</u>	<u>\$ 754,062</u>	<u>\$ 601,548</u>
<u>Demand Charge per Maximum Daily Requirement ("MDR"):</u>			
	<u>Total</u>	<u>Sales</u>	<u>Transportation</u>
Peaking Demand Costs	\$ 220,316		
Less: Over-recovered Transportation Adm. Costs			(296)
Divided by: Demand billing units (MDR therms)	<u>1,086,000</u>		<u>1,059,000</u>
Cost/(credit) per MDR therm	<u>\$ 0.20287</u>		<u>(0.00028)</u>
Distribution Demand Charge per MDR therm		<u>\$ 0.20287</u>	<u>\$ 0.20259</u>
Multiplied by: Demand Billing Units		<u>27,000</u>	<u>1,059,000</u> WP GCS-3b
Revenue Recovery		<u>\$ 5,477</u>	<u>\$ 214,543</u> <u>\$ 220,020</u>
<u>Energy Charge per therm:</u>			
	<u>Total</u>	<u>Sales</u>	<u>Transportation</u>
Average Demand Costs	\$ 410,753		
Divided by: Energy Billing units (therms)	<u>16,530,375</u>		
	<u>\$ 0.02485</u>		
Plus: Energy Costs per therm		<u>\$ 0.00589</u>	
Distribution Energy Charge per therm		<u>\$ 0.03074</u>	<u>\$ 0.02485</u>
Multiplied by: Energy Billing Units		<u>720,595</u>	<u>15,809,780</u>
Revenue Recovery		<u>\$ 22,151</u>	<u>\$ 392,873</u> <u>\$ 415,024</u>
			<u>\$ 635,044</u>

Mid-American Energy Company
Rate Design - Summary of Costs by Function and
Staff Revenue Conversion Factor

<u>Functional Costs</u>	<u>Net COS</u>	<u>Rate 60</u>	<u>Rate 70</u>	<u>Rate 85</u>	<u>Rate 87</u>	<u>Allocation Method</u>
<u>Demand-related Costs</u>						
Mains (Average)	2,978,548	1,544,392	1,003,590	421,015	9,551	Throughput (Weather Normalized)
Mains (Peaking)	3,112,926	1,749,640	1,136,758	225,820	707	Peak Demand (Total Throughput)
	<u>\$ 6,091,474</u>	<u>\$ 3,294,032</u>	<u>\$ 2,140,348</u>	<u>\$ 646,835</u>	<u>\$ 10,258</u>	
<u>Customer-related Costs</u>						
Services	\$ 3,738,485	\$ 2,615,636	\$ 1,116,981	\$ 5,216	\$ 652	Weighted Customers - Services
Meters	3,748,053	2,594,126	1,107,796	43,113	3,018	Weighted Customers - Meters
Regulators	465,273	322,028	137,519	5,352	375	Weighted Customers - Regulators
Industrial Meters	15,262	-	4,869	10,392	-	Weighted Customers - Industrial Meters
Customer Accounts	3,791,953	3,110,517	559,878	118,755	2,804	Weighted Customers - Cust Service
	<u>\$ 11,759,027</u>	<u>\$ 8,642,307</u>	<u>\$ 2,927,043</u>	<u>\$ 182,828</u>	<u>\$ 6,848</u>	
<u>Transportation Administration</u>	<u>\$ 107,202</u>	<u>-</u>	<u>\$ 97,456</u>	<u>\$ 9,746</u>	<u>-</u>	Transport Customers
<u>Energy Costs</u>						
Cost of Gas	\$ 48,872,160	\$ 33,598,844	\$ 14,759,275	\$ 273,169	\$ 240,872	Cost of Gas (Direct Assigned)
Less: PGA Recoveries	(48,535,381)	(33,367,313)	(14,657,568)	(271,287)	(239,213)	
	<u>\$ 336,779</u>	<u>\$ 231,530</u>	<u>\$ 101,706</u>	<u>\$ 1,882</u>	<u>\$ 1,660</u>	
Peak Facilities	661,505	438,206	220,703	2,465	130	Peak Demand (Sales Service Only)
	<u>\$ 998,284</u>	<u>\$ 669,736</u>	<u>\$ 322,410</u>	<u>\$ 4,348</u>	<u>\$ 1,790</u>	
Total Costs (unadjusted to Staff)	<u>\$ 18,955,986</u>	<u>\$ 12,606,075</u>	<u>\$ 5,487,257</u>	<u>\$ 843,757</u>	<u>\$ 18,897</u>	
Staff Revenue Requirement	\$ 19,008,000					
Less: Other Operating Revenues	(514,056)					
Net Revenue from Base Rates	\$ 18,493,944	same as page 3, Total Costs adjusted by Staff Revenue Conversion Factor				
Divided by: ML Cost Study Revenue Requirement (unadjusted)	<u>18,955,986</u>					
Staff Revenue Conversion Factor	<u>0.97563</u>	used in calculating charges on pages 2 and 3				

MidAmerican Energy Company
Customer Class Allocators

I. Throughput (Weather Normalized)

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
W.N. Throughput	60,637,738	39,404,125	16,530,375	374,989	116,947,227
Allocator	0.5185051	0.3369394	0.1413490	0.0032065	1.0000000

II. Peak Demand (Sales Service Only)

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Allocator	0.6624379	0.3336381	0.0037271	0.0001969	1.0000000

III. Peak Demand (Total Throughput)

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Allocator	0.5620564	0.3651736	0.0725428	0.0002272	1.0000000

IV. Customers

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Allocator	0.9211715	0.0786754	0.0001225	0.0000306	1.0000000

V. Transport Customers

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Total Customers	-	70	7	-	77
Allocator	-	0.9090909	0.0909091	-	1.0000000

VI. Weighted Customers - Services

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Weight	1.00	5.00	15.00	7.50	N/A
Weighted Customers	60,170	25,695	120	15	86,000
Allocator	0.6996512	0.2987791	0.0013953	0.0001744	1.0000000

MidAmerican Energy Company
Customer Class Allocators

VII. Weighted Customers - Meters

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Weight	1.00	5.00	125.00	35.00	N/A
Weighted Customers	60,170	25,695	1,000	70	86,935
Allocator	0.6921263	0.2955657	0.0115028	0.0008052	1.0000000

VIII. Weighted Customers - Regulators

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Weight	1.00	5.00	125.00	35.00	N/A
Weighted Customers	60,170	25,695	1,000	70	86,935
Allocator	0.6921263	0.2955657	0.0115028	0.0008052	1.0000000

IX. Weighted Customers - Industrial Meters

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Eligible Customers	-	82	7	-	89
Weight	1.00	5.00	125.00	35.00	N/A
Weighted Customers	-	410	875	-	1,285
Allocator	-	0.3190661	0.6809339	-	1.0000000

X. Weighted Customers - Customer Service - see page 4

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Total Customers	60,170	5,139	8	2	65,319
Weight	1.00	2.11	287.15	27.12	N/A
Weighted Customers	60,170	10,830	2,297	54	73,352
Allocator	0.8202941	0.1476490	0.0313175	0.0007394	1.0000000

MidAmerican Energy Company
Customer Class Allocators

XI. Manufactured Gas Cleanup

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Throughput	60,637,738	39,404,125	16,530,375	374,989	
Revenue	44,518,635	19,066,105	995,271	258,240	
COG	33,367,314	14,657,569	271,287	239,213	
Total Margin	\$ 11,151,321	\$ 4,408,536	\$ 723,984	\$ 19,027	\$ 16,302,869
Margin Allocator	0.6840097	0.2704148	0.0444084	0.0011671	1.0000000
Throughput Allocator	0.5185051	0.3369394	0.1413490	0.0032065	1.0000000
50/50	0.6012574	0.3036771	0.0928787	0.0021868	1.0000000

XII. Cost of Gas

	<u>60</u>	<u>70</u>	<u>85</u>	<u>87</u>	Total (w/o Contract)
Cost of Gas	\$ 33,367,314	\$ 14,657,569	\$ 271,287	\$ 239,213	\$ 48,535,382
Allocator	0.6874843	0.3019976	0.0055895	0.0049286	1.0000000

MidAmerican Energy Company
Class Allocation Factors

Calculation of Customer Service Weighting Factor

<u>Category of Expense</u>	<u>Amount</u>	<u>Rate 60</u>	<u>Rate 70</u>	<u>Rate 85</u>	<u>Rate 87</u>		
Direct Customer Accounting Expenses Accounts 903-905	\$ 1,604,530	60,170 1.00 60,170 0.92120	5,139 1.00 5,139 0.07868	8 1.00 8 0.00012	2 1.00 2 0.00003	65,317 1.00000	Original Weighted Customers
	\$ 1,478,093	\$ 126,241	\$ 197	\$ 49	\$ 1,604,530		
Direct Customer Information Expenses Accounts 908-910	\$ 49,541	60,170 1.00 60,170 0.92120	5,139 1.00 5,139 0.07868	8 1.00 8 0.00012	2 1.00 2 0.00003	65,317 1.00000	Number of Customers
	\$ 45,637	\$ 3,898	\$ 6	\$ 2	\$ 49,541		
Economic Development Expenses Activity 689302	\$ 57,196	\$ 11,151,321 1.00 11,151,321 0.68481	\$ 4,408,536 1.00 4,408,536 0.27073	\$ 723,984 1.00 723,984 0.04446	\$ 19,027 1.00 19,027 0.00117	\$ 16,283,842 1.00000	Margins
	\$ 39,168	\$ 15,485	\$ 2,543	\$ 67	\$ 57,196		
Marketing/EC Expenses Accounts 912-916 Less Activity 689302	\$ 192,614	- - -	39,404,125 0.70447 135,691	16,530,375 0.29553 56,923	374,989 0.00670 1,291	55,934,500 1.00000 192,614	throughput
Totals	\$ 1,562,898	\$ 281,314	\$ 59,669	\$ 1,409			
	\$ 25.97	\$ 54.74	\$ 7,458.62	\$ 704.39			
Customer Account Weights	1.000	2.107	287.149	27.118			
Rounded Weights	1.000	2.000	200.000	15.000			

MidAmerican Energy Company
 Peak Demand Estimation

(therms)

<u>Month</u>	<u>Rate 60</u>	<u>Rate 70</u>	<u>Rate 85</u>	<u>Rate 87</u>	<u>HDD</u>	<u>70 Sales</u>
Jan	11,064,039	6,797,249	2,070,360	17,643	1,268	5,192,340
Feb	8,046,801	5,835,260	2,193,481	-	863	3,899,068
Mar	5,658,784	3,930,449	1,891,382	11,526	606	2,443,622
Apr	3,902,283	2,797,673	1,584,144	5,970	427	1,645,074
May	2,149,331	1,860,978	1,479,846	4,513	112	804,427
Jun	1,279,506	1,025,347	1,205,653	85,056	29	459,395
Jul	1,277,596	1,235,596	1,146,228	59,636	-	598,508
Aug	1,310,290	874,376	810,512	25,441	-	399,132
Sep	1,464,309	1,509,052	808,773	41,720	97	637,184
Oct	2,733,971	1,906,646	730,429	29,087	263	1,073,422
Nov	7,639,933	3,897,112	931,094	54,855	866	3,092,289
Dec	12,803,430	6,992,428	1,678,470	39,542	1,601	5,303,646
Intercept	1,079,327	1,139,964	1,078,289	36,761		407,296
Slope	7,563	4,074	586	(11)		3,369
Estimated Annual Sales	61,478,259	39,819,222	16,696,686	371,926		26,504,989
Average Load	167,973	108,796	45,619	1,016		72,418
Estimated Peak Day	716,088	404,048	88,058	235		316,591
Estimated Load Factor	23.46%	26.93%	51.81%	433.33%		22.87%
W.N. Total Throughput	60,637,738	39,404,125	16,530,375	374,989		
W.N. Peak Demand	584,821	379,964	75,481	236	1,040,502	
Allocator	0.56206	0.36517	0.07254	0.00023	1.00000	
W.N. Total Sales	60,637,738	26,215,078	720,595	275,696		
W.N. Peak Demand	584,821	294,546	3,290	174	882,831	
Allocator	0.66244	0.33364	0.00373	0.00020	1.00000	

MidAmerican Energy Company
Calculation of Load Factor

(therms)	<u>Total</u>	<u>Sales</u>	<u>Transport</u>	Interdept <u>Sales</u>	Interdept <u>Transport</u>	Total <u>Sales</u>	Total <u>Transport</u>
60	60,637,738	60,637,738	-	-	-	60,637,738	-
70	39,404,125	26,215,078	12,719,450	74,987	394,610	26,290,065	13,114,060
85	16,530,375	720,595	15,809,780	-	-	720,595	15,809,780
87	374,989	275,696	99,293	-	-	275,696	99,293
Contract	<u>87,610,364</u>	<u>-</u>	<u>87,610,364</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>87,610,364</u>
Total Throughput	204,557,591	87,849,107	116,238,887	74,987	394,610	87,924,094	116,633,497
Average Throughput	558,901						
All-time Peak	<u>1,143,026</u>	ML-9 attachment, page 14					
Load Factor	48.897%						

MidAmerican Energy Company
Functional Allocation Factors

	<u>Peak Facilities</u>	<u>Mains (Average)</u>	<u>Mains (Peak)</u>	<u>Services</u>	<u>Meters</u>	<u>Regulators</u>
1 Peaking Facilities	1.0000000	-	-	-	-	-
2 Average & Peak	-	0.4889700	0.5110300	-	-	-
3 Services	-	-	-	1.0000000	-	-
4 Meters	-	-	-	-	1.0000000	-
5 Regulators	-	-	-	-	-	1.0000000
6 Direct Assign - Non Residential Customers	-	-	-	-	-	-
7 Customer Accounts	-	-	-	-	-	-
8 COG	-	-	-	-	-	-
9 MGP Cleanup	-	-	-	-	-	-
10 Transportation Administration	-	-	-	-	-	-
19 Supervised O&M	0.0337594	0.1122290	0.1172923	0.1611660	0.2573787	0.0300073
20 Gross Production, Distribution Plant	0.0429108	0.2660473	0.2780501	0.2899491	0.1014322	0.0195942
21 Gross Plant	0.0417841	0.2471088	0.2582572	0.2740929	0.1206328	0.0208763
22 Net Plant	0.0340223	0.2431455	0.2541151	0.2712946	0.1275220	0.0214354
23 Gross Distribution Plant	-	0.2779755	0.2905164	0.3029489	0.1059799	0.0204727
24 Meters & Services Plant	-	-	-	0.7408353	0.2591647	-
27 Gross Mains and Services Plant	-	0.3079848	0.3218797	0.3701355	-	-
28 Gross Meters and Regulators Plant	-	-	-	-	0.8381000	0.1619000
29 Gross Plant Excluding Intangible	0.0419087	0.2492040	0.2604469	0.2758471	0.1185086	0.0207344
30 Distribution Operation Expense Less Supervision	-	0.1712309	0.1789560	0.3721515	0.2421299	0.0350029
31 Distribution Maintenance Expense Less Supervision	-	0.2102706	0.2197570	0.1342896	0.3651458	0.0705370
32 Cust Acct Expense Less Supervision	-	-	-	-	0.2276883	-
33 Payroll Allocator	0.0307501	0.0971761	0.1015602	0.1715111	0.2666402	0.0268966
34 Customer and A&G (excludes 923, 925, 926 and 931)	0.015004	0.052414	0.054779	0.073751	0.244206	0.013165
35 Weighted Injuries and Damages	0.044841	0.139864	0.146174	0.257474	0.262038	0.039107

MidAmerican Energy Company
Functional Allocation Factors

	<u>Industrial Meters</u>	<u>Customer Service</u>	<u>Transport Admin</u>	<u>COG</u>	<u>Total</u>
1 Peaking Facilities	-	-	-	-	1.0000000
2 Average & Peak	-	-	-	-	1.0000000
3 Services	-	-	-	-	1.0000000
4 Meters	-	-	-	-	1.0000000
5 Regulators	-	-	-	-	1.0000000
6 Direct Assign - Non Residential Customers	1.0000000	-	-	-	1.0000000
7 Customer Accounts	-	1.0000000	-	-	1.0000000
8 COG	-	-	-	1.0000000	1.0000000
9 MGP Cleanup	-	-	-	-	-
10 Transportation Administration	-	-	1.0000000	-	1.0000000
19 Supervised O&M	0.0001800	0.2511047	0.0088375	0.0280450	1.0000000
20 Gross Production, Distribution Plant	0.0020163	-	-	-	1.0000000
21 Gross Plant	0.0017902	0.0309167	0.0010881	0.0034530	1.0000000
22 Net Plant	0.0017339	0.0407463	0.0014341	0.0045508	1.0000000
23 Gross Distribution Plant	0.0021067	-	-	-	1.0000000
24 Meters & Services Plant	-	-	-	-	1.0000000
27 Gross Mains and Services Plant	-	-	-	-	1.0000000
28 Gross Meters and Regulators Plant	-	-	-	-	1.0000000
29 Gross Plant Excluding Intangible	0.0018152	0.0274964	0.0009677	0.0030710	1.0000000
30 Distribution Operation Expense Less Supervision	0.0005287	-	-	-	1.0000000
31 Distribution Maintenance Expense Less Supervision	-	-	-	-	1.0000000
32 Cust Acct Expense Less Supervision	-	0.7723117	-	-	1.0000000
33 Payroll Allocator	0.0001979	0.2566738	0.0118660	0.0367281	1.0000000
34 Customer and A&G (excludes 923, 925, 926 and 931)	0.000110	0.516394	0.018174	0.012002	1.0000000
35 Weighted Injuries and Damages	0.000296	0.050804	0.002349	0.057055	1.0000000